STATE OF INDIANA

Mitchell E. Daniels, Jr.
Governor

STATE BUDGET AGENCY
212 State House
Indianapolis, Indiana 46204-2796
317/232-5610

Charles E. Schalliol
Director

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MAR - 1 2007
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

February 27, 2007

Ms. Kathryn A. Watson, Chief
Air Programs Branch
Office of Air Quality
Indiana Department of Environmental Management
100 North Senate Avenue, N1003
Indianapolis, IN 46204

Dear Ms. Watson:

Pursuant to the provisions of Executive Order 2-89 and Budget Agency Financial Management Circular 89-1, the State Budget Agency has reviewed the proposed rule to adopt 326 IAC 24-4 (LSA #05-116), which you submitted to the State Budget Agency on February 20, 2007.

After reviewing the proposed rule, the recommendation of the State Budget Agency is that the rule changes be approved.

Furthermore, the attached statement and analysis (attached hereto) provided by the Indiana Department of Environmental Management is hereby adopted as the Office of Management and Budget's own Fiscal Impact Statement for the purpose of satisfying the requirements under IC 4-22-2-28(d). Also, it is adopted as the Office of Management and Budget's cost benefit analysis under IC 4-3-22-13(a).

If you have questions concerning this action, please contact your budget analyst or Gayle Pierson at 232-5610.

Sincerely,

Charles E. Schalliol

Charles E. Schalliol
Director

2/27/07

CES/GP

Office of Management and Budget $500,000 Fiscal Impact Analysis

Agency: Indiana Department of Environmental Management (IDEM)
Rule Number: #05-116
Rule Topic: Clean Air Mercury Rule (CAMR)

Rule Summary

The draft rule adopts a mercury trading program for coal-fired electricity generating units (EGUs), larger than 25 megawatts, producing electricity for sale by adding 326 IAC 24-4. This rule is required under the federal Clean Air Mercury Rule (CAMR) published in the Federal Register on May 18, 2005 (70 FR 28606; May 18, 2006). CAMR establishes a cap on mercury emissions from EGUs in two phases (Phase I starting in 2010 and Phase II starting in 2018). CAMR is a cap and trade program that allows interstate trading and banking of allowances. EGUs demonstrate compliance by holding one allowance for each ounce of mercury emitted in any given year. The CAMR Phase 1 cap for Indiana is 4,194 pounds and the Phase II is 1,656 pounds. In Indiana, there are 71 units, 8 of which have either shut down or repowered and will initially receive mercury allowances under the cap and trade program, at 9 companies that are affected by this rule. The Indiana Air Pollution Control Board (APCB) also has pending a rulemaking petition from the Hoosier Environmental Council (HEC) to regulate EGUs to control mercury emissions by 90% or to meet a mercury emission rate equal to 0.6 lb/trillion Btu, whichever is more readily achievable. The petition allows plant-wide emissions averaging as compliance flexibility.

Fiscal Impact

CAMR is required under federal law; the draft rule is based on CAMR. If Indiana does not adopt a rule that is at least as stringent as CAMR, U.S. EPA would adopt and implement a federal plan in Indiana. A federal plan for CAMR means that Indiana would lose the ability to establish an allocation methodology for mercury allowances that works best for Indiana. However, IDEM is presenting a range of fiscal impacts with the cost of CAMR (draft rule language) at the low end (this fiscal impact is imposed by the federal rule and not the state) and the cost of the HEC petition at the high end (Table 1). Should the APCB provide direction to pursue alternatives to the draft rule or there are significant changes to the draft rule, the costs of the rule would be greater than the estimated costs for the CAMR-based draft rule language, but would fall somewhere in this range. Both IDEM and the Indiana Utility Group (IUG) have estimated the impact of the draft rule based on CAMR and the HEC petition.

Table 1: Summary of Mercury Control Impacts

Draft Rule 326 IAC 24-4 (Based on Federally Required CAMR)		
Phase I (2010)	IDEM	IUG
*Total Annual cost (retrofit controls+ emission monitoring+allowance trading), million $	-26	-1
Increase in electricity rates (incremental to CAIR), %	-0.24%	0.14%

Phase 2 (2018)		
Total Annual cost (retrofit controls+ emissions monitoring+allowance trading+additional capacity), million $	64	68
Increase in electricity rates (incremental to CAIR),%	0.79%	1.06%
HEC Petition (beginning 2010)		
	IDEM	IUG
*Total Annual cost (retrofit controls+ emissions monitoring), million $	207	373
Increase in electricity rates (incremental to CAIR), %	2.80%	5.00%

Fiscal Impact on State and Local Government

The draft rule based on CAMR impacts 1 state or local source: Richmond Power & Light (RP&L). RP&L has two operating units. Both IDEM and IUG cost analyses project that Unit 1 will be retired beginning in 2010. The cost estimates include emissions monitoring and allowance trading costs on the source. The IDEM analysis projects a cost of $3,500 annually for Phase 1 and net revenue of $323,500 annually for Phase II. The IUG analysis projects net revenue of $734,250 for Phase 1 and $415,250 annually for Phase II, indicating that the source will have surplus allowances to trade in both phases.

Under the HEC petition there would be retrofit control and emissions monitoring costs on the source. Both IDEM and IUG estimate that the source will be required to meet a 90% emissions reduction and will install activated carbon injection plus fabric filter (ACI+FF) to achieve that reduction. The total annual cost of emissions monitoring and retrofit control is estimated between $2 million (IUG) and $2.6 million (IDEM) beginning in 2010.

Small Business Fiscal Impact

This rule does not apply to small businesses, but electricity rates for small businesses could increase as described in Table 1.

Additional Rule Information

Mercury emissions are a health concern because once mercury is released to the air from coal combustion and other sources mercury can fall to the earth through wet and dry deposition. After it settles in lake or river sediments, mercury can be converted by bacteria into methylmercury, a more toxic form of mercury. Methylmercury can build up in fish tissue and be consumed by people and wildlife. Those at greatest risk from exposure include children where the effects from prenatal exposure can occur even at doses that do not result in effects in the mother. The Hoosier Environmental Council (HEC) also submitted a petition to reduce mercury emissions from coal-fired EGUs to the Indiana Air Pollution Control Board (IAPCB) requesting that the board regulate EGUs to control mercury emissions by 90% or meet an emission rate equal to 0.6 lb/trillion Btu, whichever is more readily achievable. The petition allows plant-wide emissions averaging as compliance flexibility, but no interstate trading.

Sources of Information

1. Second Notice of Comment Period. January 17, 2007. Available at: http://www.in.gov.legislative/iac/irtoc.htm.
2. HEC. Proposed Draft Rulemaking Language for Emission Limitations for Mercury from Coal-Fired Electricity Generating Utilities in Indiana. Presented to IAPCB at its July 7, 2004, meeting.
3. Dr. Indra Frank, HEC. E-mail to Kathy Watson and Susan Bem. Amendments to Proposal. September 15, 2005.
4. U.S. EPA. Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule. 70 FR 28606; May 18, 2005. Available at http://www.epa.gov/air/mercury rule/rule.html.
5. IDEM. Mercury Control Costs (CAMR Phase I and HEC Petition). November 2005.
6. IUG. Indiana Utility Group Comments on IDEM Fiscal Impact Analysis of the 90% Mercury Reduction MACT Proposal. January 2006.
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10. U.S. EPA. Standalone Documentation for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model. EPA 430-R-05-011. September 2005. Available at: http://www.epa.gov/airmarkets/epa-ipm/bc/intro.pdf.
11. SUFG. Final Report: Projected Impacts of Mercury Emissions Reductions on Electricity Prices in Indiana. September 2006. Available at: http://www.purdue.edu/dp/energy/pdf/Mercury%20paper.pdf.
12. Clean Air Interstate Rule. Final Adopted by APCB November 1, 2006. LSA #05-117
13. IDEM. Clean Air Interstate Rule Cost Impact Analysis. March 31, 2006, and Amendments November 2006. Available at: http://www.in.gov/idem/rules/archive/packets/air/2006/jun/index.html and http://www.in.gov/idem/rules/archive/packets/air/2006/nov/index.html.
14. U.S. EPA. Cost Estimates for Mercury Emissions Monitoring. CAMR Rulemaking Docket, Document ID: OAR-2002-0056-6161, Available at: http://www.regulations.gov.
15. U.S. EPA. Regulatory Impact Analysis of the Clean Air Mercury Rule. Final Report. EPA-452/R-05-003. March 2005. Available at: http://www.epa.gov/ttn/atw/utility/utiltoxpg.html.
16. National Association of Clean Air Agencies. State Mercury Program for Utilities. December 2006. Updates available at: http://www.cleanair.org.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
CLEAN AIR MERCURY RULE (CAMR) CAP AND TRADE PROGRAM
326 IAC 24-4
COST IMPACT ANALYSIS

Introduction and Summary

This document presents the cost impacts of the draft rule 326 IAC 24-4, concerning mercury emissions control from coal-fired power plants (1) and a petition submitted to the Indiana Air Pollution Control Board (APCB) by the Hoosier Environmental Council (HEC) in its June 2, 2004 meeting (2) (modified to be more specific to power plants in September 2005 (3)). The draft rule, published in the Indiana Register on January 17, 2007, follows the U.S. EPA Clean Air Mercury Rule (CAMR) published in the Federal Register on May 18, 2005 (70 FR 28606; May 18, 2005) (4) with a different allowance allocation methodology; a flexibility allowed in the CAMR. CAMR is required under federal law and the minimum requirements of CAMR would eventually apply to affected sources regardless of Indiana's rulemaking. The draft rule is applicable to the Indiana coal-fired electricity generating units, larger than 25 MW, producing electricity for sale (also known as EGUs). The rule establishes caps on mercury emissions from the EGUs reducing emissions in two phases (Phase I starting in 2010 and Phase II starting in 2018), allocates allowances to the EGUs and allows interstate trading and banking of allowances. The HEC petition requires EGUs to control mercury emissions by 90% or meet an emission rate equal to 0.6 lb/trillion Btu, whichever is more readily achievable, by 2010. The petition allows plant-wide emissions averaging as compliance flexibility.

To help the policymakers make an informed decision on a control strategy, the Indiana Department of Environmental Management (IDEM) and the Indiana Utility Group (IUG) estimated the costs of the above two scenarios. (5, 6, 7, 8, 9) Both used the Integrated Planning Model (IPM) developed by the ICF Inc. to analyze the U.S. power sector with different assumptions such as that of electricity demand growth, pollution control costs and fuel costs. IPM provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the projected controls from policies to limit emissions from the electric power sector. Documentation of the IPM can be found at (10). Upon request of the IDEM, the State Utilities Forecasting Group (SUFG), located at Purdue University, West Lafayette, Indiana, estimated the impact of these costs on the electricity rates for Indiana consumers. (11)

Table 1 below, gives a summary of the costs and their impacts on electricity rates. The impacts are discussed in greater details in the Results and Discussion section. As seen in Table 1, the draft rule will result in revenue (due to allowance trading) to the EGUs in Phase I and impose costs in Phase II. The costs in Phase II are mainly due to the reduction in the Indiana budget by 60.5% which reduces the potential for allowance trading revenues and requires retrofit controls for compliance (Phase I budget is 4,194 lbs; Phase II budget is 1,656 lbs). The HEC petition is projected to impose costs significantly higher than the draft rule. This is due to more stringent emissions limitations and limited compliance flexibility allowed by this control scenario (no allowance trading). The HEC strategy is estimated to achieve 42% to 56% emissions reductions beyond those expected to be achieved by the draft rule, beginning in year 2010. The analysis projects that a large number of Indiana EGUs will install retrofit controls in the form of activated carbon injection with fabric filter (ACI+FF), a control technology more thoroughly studied than other mercury specific control technologies, to meet the proposed emission limitations.

Table 1: Summary of Mercury Control Impacts

Draft Rule 326 IAC 24-4		
Phase I (2010)	IDEM	IUG
*Total Annual cost (retrofit controls+ emission monitoring+allowance trading), million $	-26	-1
Increase in electricity rates (incremental to CAIR), %	-0.24%	0.14%
Phase 2 (2018)		
Total Annual cost (retrofit controls+ emissions monitoring+allowance trading+additional capacity), million $	64	68
Increase in electricity rates (incremental to CAIR),%	0.79%	1.06%
HEC Petition (beginning 2010)		
	IDEM	IUG
***Total Annual cost (retrofit controls+ emissions monitoring), million $**	**207**	**373**
Increase in electricity rates (incremental to CAIR), %	2.80%	5.00%
* Costs are different from Table 2 due to rounding		

Mercury control impacts are in 2005 dollars and are incremental to the Clean Air Interstate Rule (CAIR). The APCB final adopted the CAIR in November 2006. [12] The fiscal impact of this rule can be found in reference #13.

Indiana's draft rule is based on the federal CAMR. Upon request from several interested parties, the APCB charged a subgroup of the air board to work with a group of experts (APCB Mercury Emissions Study Group) to delineate factors the APCB should consider in deciding on mercury policy alternatives. Should the APCB provide direction to pursue alternatives to the draft rule or there are significant changes to the draft rule, the costs of the rule would be greater than the estimated costs for the CAMR based draft rule, but should be less than the HEC petition costs.

Methodology

Both IDEM and IUG used the Integrated Planning Model (IPM) in their cost analyses. The IPM, developed by ICF Consulting, Inc., is a multi-regional, dynamic, deterministic linear programming model of the U. S. electric power sector. The model has evolved over a number of years, for example, the 2002 version 2.1 was updated in 2003 as version

2.1.6, which was further updated in 2004 as version 2.1.9. The details can be found at (10).

The model requires input parameters that characterize the U. S. electric system, economic outlook, fuel supply and air regulatory framework. The model has the capability of producing a broad range of outputs such as capacity additions and retirements, capacity prices, wholesale electricity prices, power production costs, fuel consumption, fuel prices, allowance prices and emissions (NO_x, SO_2, CO_2, and mercury).

IDEM used the IPM analysis performed by U.S. EPA for its CAMR regulatory impact analysis. IUG ran IPM with significantly different assumptions for electricity demand growth, pollution controls and fuel costs; and an updated EGU database. For example, IUG assumed an average electricity load growth equal to 1.77% for the period 2007-2020 as compared to the U.S. EPA assumption equal to 1.55%. The IUG estimate is based on the EIA's Annual Energy Outlook (AEO) for 2005 and North American Electric Reliability Council (NERC) forecasts. The U.S. EPA estimate is based on the AEO 2004 sales forecasts, adjusted for reduction in electricity consumption due to voluntary programs operated by the Department of Energy and the U.S. EPA. The IUG pollution control capital costs are 60% to 100% higher than the U.S. EPA assumptions. The IUG control costs are based on the market data and the experience of its members, in particular, with the post-combustion NO_x controls, such as selective catalytic reduction systems (SCRs) and selective non-catalytic reduction systems (SNCRs), installed in Indiana in response to the NO_x SIP Call. The U.S. EPA control costs are based on the engineering equations and cost factors developed from surveys. The IUG fuel cost estimates are 23% to 47% higher than the U. S. EPA. The IUG estimates are based on the AEO 2005 forecasts and market data, while the U.S. EPA data are based largely on the AEO 2003 forecasts. IUG updated the EGU database that U.S. EPA used, known as the National Electric Energy Data System (NEEDS). NEEDS is a repository of information for the existing and planned-committed units. The updates included corrections to the capacities and the pollution control systems. The accuracy of this database affects the compliance decisions and hence the emissions and costs.

Draft rule costs include the costs of retrofit controls, emissions monitoring, allowance trading, and any additional capacity needed to meet the electricity demand under the draft rule control scenario. Retrofit controls costs include the capital and the annual fixed and variable operation and maintenance (O&M) costs of the control equipment. These costs were estimated for the controls projected by IPM. Cost factors in \$/kW for capital cost, \$/kw-yr for fixed O&M cost and mills/kWh for variable O&M cost and the EGU data such as the capacity of the unit and the amount of electricity generated were used to estimate these costs in million dollars for the projected controls. IDEM obtained the cost factors from the IPM documentation while IUG used its own factors as stated above. The capital costs were annualized assuming the equipment life as 15 years and a capital charge rate equal to 12%. The annualized capital and the annual O&M costs were added together to estimate the annual cost of the retrofit controls.

Emissions monitoring costs include the installation and the operating and maintenance (O&M) costs of the monitoring equipment. Cost estimates assume the installation of continuous emissions monitoring system (CEMS) to monitor mercury emissions. IDEM and IUG used different capital costs but the same O&M costs of the CEMS. IDEM capital costs are based on the U.S. EPA estimate equal to $70,000 which assumes that the EGUs will be able to use existing systems for mercury emissions monitoring without major modifications.[14] IUG, in its estimates, assumed a totally new monitoring system with an installed cost equal to $285,000 per system. Both IDEM and IUG have used U.S. EPA estimated annual cost of O&M equal to $87,000.

Allowance trading cost is the product of the difference between the Indiana budget and projected emissions (lbs) and the projected allowance price ($/lb). IDEM used the projected allowance prices in Table 7-8 of the U.S. EPA CAMR regulatory impact analysis (RIA).[15] IUG used the allowance prices projected in its IPM analysis. The allowance prices in the U.S. EPA RIA are $23,200/lb and $39,000/lb respectively for Phase I and Phase II in 1999 dollars. These values were multiplied by a factor of 1.20 to express them in 2005$. IUG used $37,968/lb and $60,636/lb respectively for Phase I and Phase II in its analysis. These values are in 2005 dollars.

Additional capacity cost is the cost of capacity incremental to CAIR needed to meet the electricity demand growth under the rule. This cost was estimated using the cost factors in the IPM documentation, Exhibits 4-9 and 4-11.[10]

HEC petition costs include the costs of retrofit controls and emissions monitoring. The HEC petition does not have the provision for interstate allowance trading; it allows within plant averaging. Both IDEM and IUG used the cost factors in the IPM documentation to estimate the cost of mercury control. The difference is in the assumptions and data used. IDEM estimates are based on a plant-wide 90% control or 0.6 lb/trillion Btu emission rate; IUG estimates are based on a 90% unit-specific control. IDEM, in its estimate, did not consider the cost of additional controls on units that presently have or are projected to have a combination of particulate matter (PM), nitrogen oxide (NO_x) and sulfur dioxide (SO_2) controls. This combination of controls is electrostatic precipitators (ESP) or fabric filters (FF) for PM control, selective catalytic reduction system (SCR) for NO_x control and flue gas desulfurization (FGD) for SO_2 control. U.S. EPA estimates a 90% mercury removal for this control configuration. IUG applied controls on these units assuming that this control configuration (ESP or FF, SCR, and FGD) would not achieve 90% removal. Recent tests at Hoosier Energy Merom Units with this control configuration have shown less than 90% mercury removal. IDEM used historical data (such as the fuel sulfur and heat contents and the amount of electricity generated) from the Department of Energy, Energy Information Administration (EIA) Form 767 for the year 2003 while IUG obtained these data from its Integrated Planning Model (IPM) analysis. Both IDEM and IUG did not include in their cost estimates the units projected by IPM to retire (Edwardsport Units 7-1, 7-2, and 8-1; Whitewater Valley Unit 1). IDEM did not include in its estimates units not currently operating (Mitchell Units 4, 5, 6 and 11); IUG included these units in its cost estimates.

There is a significant difference in the emissions monitoring assumptions used by IDEM and IUG. IDEM assumed one CEMS at the outlet at units that will be required to meet the 0.6 lb/trillion Btu emission rate. IDEM assumed a completely new system at the inlet and the existing system with modifications at the outlet for units that will be required to meet a 90% emissions reduction. IUG, since it based its estimates on a 90% control from the inlet at each unit, assumed a new CEMS at the inlet and a new CEMS at the outlet. The differences in the cost assumptions have been discussed above.

<u>Electricity Rate Impact Analysis</u>
The electricity rate impact analysis is described in details at (11). SUFG used a traditional regulation model to analyze the impact of the EGU costs on electricity prices. The model projects electric energy sales and peak demand as well as future electric rates given a set of exogenous factors. These factors describe the future of the Indiana economy and prices of fuels that compete with electricity in providing end-use services or are used to generate electricity. Combinations of econometric and end-use models are used to project electricity use for the major customer groups: residential, commercial, and industrial. The modeling system predicts future electricity rates for these sectors by simulating the cost-of-service based rate structure traditionally used to determine rates under regulation. In this type of rate structure, ratepayers are typically allocated a portion of capital costs and fixed operating costs based on the customers' service requirements and are assigned fuel and other variable operating costs based upon the electric utility's out–of –pocket operating costs.

The SUFG performed the analysis for the five investor–owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Duke Energy, and Southern Indiana Gas & Electric Company) and three major not–for-profit entities (Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association) that supply electric power to Indiana customers. The statewide electricity prices reported here were determined using energy-weighted averages of the five investor-owned utilities for the residential, commercial, and industrial sectors as well as for all customer groups combined. The rates for the units not regulated by the IURC were not analyzed (Indiana- Kentucky Electric, Stateline Dominion, and Richmond Power & Light).

<u>Results and Discussion</u>
Table 2 shows the detailed costs and impacts of the two control scenarios.

Under the draft rule, in Phase I, both IDEM and IUG project no retrofit controls incremental to CAIR. The rule follows U.S. EPA CAMR which in Phase I relies on the CAIR co-benefit controls. Both IDEM and IUG project surplus allowances available for trading. IDEM projects 1,089 allowances while IUG projects 175 allowances. In Phase II, due to reduction in the mercury budget, both IDEM and IUG project retrofit controls. IDEM projects SCRs at four units (Petersburg Units 1 and 4 and Schahfer Units 17 and 18) while IUG projects ACI+FF at eight units (Stateline Unit 4; Schahfer Units 14 and 15; Michigan City Unit 12; Rockport Units MB1 and MB2; and Tanners Creek Units U2 and U3). IDEM projects a need for EGUs to purchase 369 allowances while IUG projects 164 surplus allowances. IDEM projects 43 MW in additional capacity, incremental to CAIR, to meet electricity demand. The additional capacity is projected to be an Integrated Gasification Combined Cycle (IGCC) system. IUG does not project additional capacity under this control scenario.

Under the HEC petition, IDEM projects ACI+FF at thirty-four units and ACI only at seven units. IUG, since it assumes that the ESP+SCR+FGD control configuration does not achieve 90% mercury reduction and it applies a 90% control at each unit, projects ACI+FF at all units except two, i.e., Stateline Unit 3 and Wabash River Unit 1A. Stateline Unit 3 presently has a FF and Wabash River Unit 1A is an IGCC with a presumed low mercury emitting potential. At Stateline Unit 3 IUG projects an ACI system only. The cost of the ACI+FF systems is estimated to range between \$2.6 million and \$58 million in capital and \$761,940 and \$18.7 million in total annual costs (annualized capital cost and annual fixed and variable O&M costs). The cost of ACI systems (without FF) is estimated to range between \$332,809 and \$21.5 million in capital and \$453,145 and \$6.8 million total annual costs (annualized capital cost and annual fixed and variable O&M costs).

Table 2: Mercury Control Impact Analysis Results

Draft Rule 326 IAC 24-4		
Phase I (2010)	**IDEM**	**IUG**
Retrofit controls	none incremental to CAIR	none incremental to CAIR
CEMS		
Number	43	45
Capital cost (million$)	3.01	12.825
Annual cost (annualized capital cost and annual O&M costs), million $	4.183	5.800
Allowance trading cost (million$)	-30.318	-6.653
Total Annual cost (retrofit controls+ CEMS+allowance trading), million $	-26.135	-0.853
Increase in electricity rates (incremental to CAIR), (%)	**-0.24%**	**0.14%**
Phase 2 (2018)		
Retrofit controls		
Capital cost (million $)	156.46	225.14
Annual cost (annualized capital cost and annual fixed and variable O&M costs), million$	30.79	71.81
CEMS		
Number	43	45
Capital cost (million$)	3.01	12.825
Annual cost (annualized capital cost and annual O&M costs), million $	4.183	5.800
Allowance trading cost (million$)	17.284	-9.936
Additional capacity		none
Capital cost (million $)	50.51	
Annual cost (million $)	10.227	
Emissions monitoring (additional capacity)		
Capital cost (million $)	3.23	

Annual cost (million $)	1.711	
Total Annual cost (retrofit controls+ CEMS+allowance trading+additional capacity), million $	64.195	67.674
Increase in electricity rates (incremental to CAIR), (%)	**0.79%**	**1.06%**
HEC Petition (2010)		
	IDEM	**IUG**
Retrofit controls		
Capital cost (million $)	621.869	1151.057
Annualized capital cost (million$)	81.759	138.126
Annual fixed O&M cost (million$)	87.624	160.419
Annual variable O&M cost (million$)	31.492	60.414
Total annual cost (annualized capital cost and annual fixed and variable O&M costs), million$	200.875	358.959
CEMS		
Number	65	110
Total capital cost (million$)	6.31	31.35
Total annualized capital cost (million $)	0.928	4.608
Total O&M cost (million $)	5.655	9.57
Total annual cost (annualized capital cost and annual O&M costs), million $	6.583	14.178
Total Annual cost (retrofit controls+ CEMS), million $	207.458	373.137
Increase in electricity rates (incremental to CAIR), (%)	**2.80%**	**5.00%**

Uncertainties in the analysis

As can be seen from the above discussion, the projections of controls and therefore costs presented in this document are sensitive to a number of assumptions such as fuel prices, electricity demand growth and the pollution control cost and effectiveness. In addition, the IPM analysis used in these cost estimates assumes a region wide emissions trading program. U.S. EPA allows states an option not to participate in the emissions trading program. As of December 2006, seventeen states were considering not allowing interstate emissions trading. [16] This may significantly increase the cost of the draft rule. The analysis does not take into account the changes in the cost and effectiveness of pollution controls in future.

As stated above, for the HEC petition, both IDEM and IUG used the cost data for ACI with and without FF, in the IPM documentation. This procedure considered only the installation of retrofit controls as a compliance option. An IPM analysis of this control scenario, taking into account other variables such as the fuel supply and costs and electricity demand growth, and considering a broader spectrum of compliance options such as retiring one or more units (if the operation of those units is determined uneconomical) and addition of new capacity to meet the projected electricity demand, fuel switching and re-powering, may project different costs. Due to resource limitations, an IPM analysis has not been developed for the HEC petition and therefore an estimate of how those costs would compare with the costs presented in this document has not been done.

References

1. Second Notice of Comment Period. January 17, 2007. Available at: http://www.in.gov.legislative/iac/irtoc.htm.
2. HEC. Proposed Draft Rulemaking Language for Emission Limitations for Mercury from Coal-Fired Electricity Generating Utilities in Indiana. Presented to APCB at its July 7, 2004, meeting.
3. Dr. Indra Frank, HEC. E-mail to Kathy Watson and Susan Bem. Amendments to Proposal. September 15, 2005.
4. U.S. EPA. Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule. 70 FR 28606; May 18, 2005. Available at http://www.epa.gov/air/mercury rule/rule.html.
5. IDEM. Mercury Control Costs (CAMR Phase I and HEC Petition). November 2005.
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16. National Association of Clean Air Agencies. State Mercury Program for Utilities. December 2006. Updates available at: http://www.cleanair.org.

Note: This document presents a concise description of the costs and impacts of the above two control scenarios. In the cost analysis a large number of spreadsheets were developed and a number of reports and voluminous IPM runs were consulted. To expeditiously obtain a reference not shown in the list of references as available

on the Internet please contact Susan Bem at (317)-233-5697 or sbem@idem.IN.gov or Shri Harsha at (317)-232-8228 or sharsha@idem.IN.gov